Chapter B3: Electricity Market Model Analysis

Introduction

The proposed section 316(b) Phase II Existing Facilities Rule applies to a subset of facilities within the electric power generation industry. The proposed rule applies to steam electric generating units that use cooling water withdrawn directly from waters of the U.S. Generating units with a non-steam prime mover and those steam units that use cooling water from a source other than a water of the U.S. are not subject to this rule. In addition, this rule only applies to plants with a design intake flow of at least 50 million gallons per day (MGD). However, due to interdependencies within the electric power market, impacts on in-scope facilities may result in indirect impacts throughout the industry. Direct impacts on plants subject to the rule may include changes in generation, profitability, and capacity utilization. Potential indirect impacts on the electric power industry may include changes to the generation and revenue of facilities and firms not subject to the rule, changes to bulk system reliability, and regional and national impacts such as changes in the price and demand for electricity.

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EPA used ICF Consulting's Integrated Planning Model (IPM®), an integrated energy market model, to conduct the economic analyses supporting the proposed section 316(b) Phase II Rule. The model addresses the interdependencies within the electric power market and accounts for both direct and indirect impacts of regulatory actions. EPA used the model to analyze two potential effects of the proposed rule and other regulatory options: (1) potential energy effects at the national and regional levels, as required by Executive Order 13211 ("Actions Concerning Regulations That Significantly Affect Energy Supply, Distribution, or Use"); and (2) potential economic impacts on in-scope facilities.

The remainder of this chapter presents an overview of the IPM and the results of the IPM analysis for the proposed rule. *Chapter B8: Alternative Options - Electricity Market Model Analysis* presents the IPM analysis for two alternative regulatory options considered by EPA.

B3-1 Summary Comparison of Energy Market Models

EPA conducted research to identify models suitable for analysis of environmental policies that affect the electric power industry. Through a review of forecasting studies and interviews with industry personnel, EPA identified three potential models and considered each for the analyses in support of the proposed Phase II Rule: (1) the Department of Energy's National Energy Modeling System (NEMS), (2) the Department of Energy's Policy Office Electricity Modeling System (POEMS), and (3) ICF Consulting's Integrated Planning Model (IPM). These models are widely used in the analysis of various issues related to public policies affecting the electric power generation industry and have been reviewed.[1]

The three models considered by EPA were developed to meet the specific needs of different users; they therefore differ in terms of structure and functionality. EPA established a set of modeling and logistical criteria to select the model that is best

[1] EPA also considered other models that are more commonly used for private sector analyses but decided to focus its model selection process on models developed for public policy analyses.

suited for the analysis of the proposed rule and alternative regulatory options. Modeling criteria refer to the models' technical capabilities that are required to provide the outputs necessary for the analysis of the proposed rule. They include the following:

- ***Redefining model plants*** – The energy market models considered by EPA aggregate similar generating units into model plants to reduce the amount of time required to run the model. However, such an aggregation is usable only if the aggregated units are similar in the base case and also have similar compliance requirements under the analyzed policy cases. The Phase II compliance requirements of in-scope facilities are based on the location, design, construction, and capacity of their cooling water intake structures (CWIS). In contrast, the existing aggregation of these models is based on factors including unit age, unit type, fuel type, capacity, and operating costs. Therefore, the model used for the Phase II analysis had to be able to accommodate a different aggregation scheme for model plants or even to run all in-scope facilities as separate model plants.

- ***Predicting the economic retirement of generating capacity*** – Compliance with the proposed Phase II Rule may increase the capital and operating costs of some facilities to a point where it is no longer economically profitable to operate the facility, or one or more of its generating units. The economically sound decision for a firm owning such a facility or unit would be to retire the facility or unit rather than comply with the regulation. Therefore, the model needed to have the ability to project early retirements as a result of compliance with the proposed rule and the market's response to such closures, including increased capacity additions or increased market prices. In addition, to support EPA's economic impact analysis, the model had to be able to map early retirements to specific facilities or units.

- ***Representing the impact of structural changes to the industry from deregulation*** – Assumptions regarding deregulation of the electric utility industry could impact a model's ability to accurately depict the profit maximizing decisions of firms. Deregulation of the wholesale market for electricity is expected to reduce wholesale prices as competition in markets increases. These changes may impact decisions regarding the retirement of existing generating units, investment in new generating units, and technology and fuel choices for new generation capacity. Therefore, it was necessary for the market model to reflect the most recent trends in the deregulation of wholesale energy markets.

EPA also considered a number of logistical criteria to determine the most appropriate model for the analyses of the proposed Phase II Rule. While a given model may be desirable from an analytical perspective, its use may be restricted due to other limitations unrelated to the model's capabilities. The logistical criteria used to evaluate each model refer to administrative issues and include the following:

- ***Availability of the model*** – Due to the tight regulatory schedule of the Phase II Rule, the model selected for this analysis had to be accessible at the time data inputs were available, and had to be able to turn around the analyses in a relatively short period of time. Some of the models considered for this analysis are used to conduct analyses in support of annual reports. Such requirements may limit access to the model and the staff required to execute the model, and therefore prevent the use of the model for this analysis.

- ***Sufficient documentation of methods and assumptions*** – Sufficient documentation of the model structure and assumptions was required to allow for the necessary review of results and procedure. While it may not be possible to disclose specific details of the structure and function of a model, a general discussion of the mechanics of the model, its assumptions, inputs, and results was required to make a model useable for this analysis.

- ***Cost –*** EPA considered the cost of using each model together with each model's ability to satisfy the other modeling and logistical criteria in determining the most appropriate model for the analysis of this rule. The model had to be sufficiently robust with respect to the other criteria while remaining within the budget constraints for this analysis.

EPA assessed each market model with respect to the aforementioned modeling and logistical criteria and determined that the IPM was best suited for the Phase II analysis.[2] A principal strength of the IPM as compared to other models is the ability to evaluate impacts to specific facilities subject to this rule. Another important advantage of the IPM model is that it has a history of prior use by EPA. The Agency has successfully used the IPM in support of a number of major air rules. Finally, the IPM model has been reviewed and approved by the Office of Management and Budget (OMB).

[2] Please see Section B3-A.1 of the appendix to this chapter for a comparison of the three electricity market models considered for this analysis.

B3-2 INTEGRATED PLANNING MODEL OVERVIEW

This section presents a general overview of the capabilities of the IPM, including a discussion of the modeling methodology, the specification of the model for the section 316(b) analysis, and model inputs and outputs.

B3-2.1 Modeling Methodology

a. General framework

The IPM is an engineering-economic optimization model of the electric power industry, which generates least-cost resource dispatch decisions based on user-specified constraints such as environmental, demand, and other operational constraints. The model can be used to analyze a wide range of electric power market issues at the plant, regional, and national levels. In the past, applications of the IPM have included capacity planning, environmental policy analysis and compliance planning, wholesale price forecasting, and asset valuation.[3]

The IPM uses a long-term dynamic linear programming framework that simulates the dispatch of generating capacity to achieve a demand - supply equilibrium on a seasonal basis and by region. The model seeks the optimal solution to an "objective function," which is a linear equation equal to the present value of the sum of all capital costs, fixed and variable operation and maintenance (O&M) costs, and fuel costs. The objective function is minimized subject to a series of user-defined supply and demand, or system operating, constraints. Supply-side constraints include capacity constraints, availability of generation resources, plant minimum operating constraints, transmission constraints, and environmental constraints. Demand-side constraints include reserve margin constraints and minimum system-wide load requirements. The optimal solution to the objective function is the least-cost mix of resources required to satisfy system wide electricity demand on a seasonal basis by region. In addition to existing capacity, the model also considers new resource investment options, including capacity expansion or repowering at existing plants as well as investment in new plants. The model selects new investments while considering interactions with fuel markets, capacity markets, power plant cost and performance characteristics, forecasts of electricity demand, reliability criteria, and other constraints. The resulting system dispatch is optimized given the resource mix, unit operating characteristics, and fuel and other costs, to achieve the most efficient use of existing and new resources available to meet demand. The model is dynamic in that it is capable of using forecasts of future conditions to make decisions for the present.[4]

b. Model plants

The model is supported by a database of boilers and electric generation units which includes all existing utility-owned generation units as well as those located at plants owned by independent power producers and cogeneration facilities that contribute capacity to the electric transmission grid. Individual generators are aggregated into model plants with similar O&M costs and specific operating characteristics including seasonal capacities, heat rates, maintenance schedules, outage rates, fuels, and transmission and distribution loss characteristics.

The number and aggregation scheme of model plants can be adjusted to meet the specific needs of each analysis. The EPA Base Case 2000 contains 1,390 model plants.[5]

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[3] The EPA Base Case 2000 is the latest EPA specification of the U.S. power market using the IPM. Past applications of the IPM for EPA analyses have used a predecessor EPA base case specification. Section B3-A.2 of the appendix to this chapter contains a summary of the major differences between the EPA Base Case 2000 and the previous EPA base case specification.

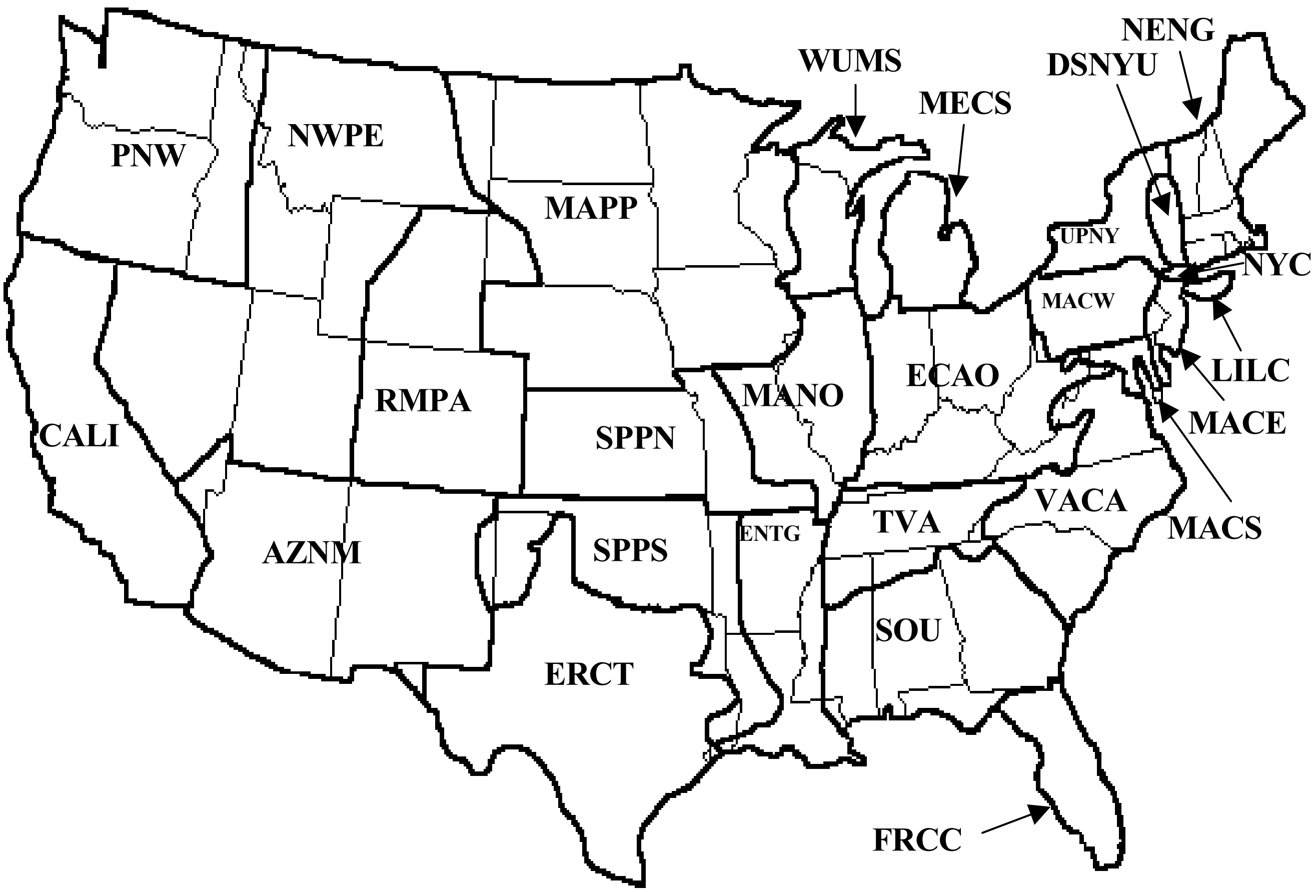
[4] EPA used the IPM to forecast operational changes, including changes in capacity, generation, revenues, electricity prices, and plant closures, resulting from the rule. In other policy analyses, the IPM is generally also used to determine the compliance response for each model facility. This process involves selecting the optimal response from a menu of compliance options that will result in the least-cost system dispatch and new resource investment decision. Compliance options specified by IPM may include fuel switching, repowering, pollution control retrofit, co-firing multiple fuels, dispatch adjustments, and economic retirement. EPA did not use this capability to choose the compliance responses of the facilities subject to section 316(b) regulation. Rather EPA exogenously estimated a compliance response using the costs of technologies capable of meeting the percentage reductions required under the regulation. In the post-compliance analysis, these compliance costs were added as model inputs to the base case operating and capital costs.

[5] Since the EPA Base Case 2000 model plants were initially created to support air policy analyses, the original configuration was not appropriate for the section 316(b) analysis. As a result, in support of this economic analysis, the facilities subject to the Phase II Rule were disaggregated from the IPM model plants and "run" as individual units along with the other model plants.

c. IPM regions

The IPM divides the U.S. electric power market into 26 regions in the contiguous U.S. It does not include generators located in Alaska or Hawaii. The 26 regions map into North American Reliability Council (NERC) regions and sub-regions. The IPM models electric demand, generation, transmission, and distribution within each region and across the transmission grid that connects regions. For the analyses presented in this chapter, IPM regions were aggregated back into NERC regions. Figure B3-1 provides a map of the regions included in the IPM. Table B3-1 presents the crosswalk between NERC regions and IPM regions.

Figure B3-1: Regional Representation of U.S. Power System as Modeled in IPM



Source: U.S. EPA, 2002.

Table B3-1: Crosswalk between NERC Regions and IPM Regions

NERC Region	IPM Regions
ASCC – Alaska	Not Included
ECAR – East Central Area Reliability Coordination Agreement	ECAO, MECS
ERCOT – Electric Reliability Council of Texas	ERCT
FRCC – Florida Reliability Coordinating Council	FRCC
HI – Hawaii	Not Included
MACC – Mid Atlantic Area Council	MACE, MACS, MACW
MAIN – Mid-America Interconnect Network	MANO, WUMS
MAPP – Mid-Continent Area Power Pool	MAPP
NPCC – Northeast Power Coordination Council	DSNY, LILC, NENG, NYC, UPNY
SERC – Southeastern Electricity Reliability Council	ENTG, SOU, TVA, VACA
SPP - Southwest Power Pool	SPPN, SPPS
WSCC – Western Systems Coordinating Council	AZNM, CALI, NWPE, PNW, RMPA

Source: U.S. EPA, 2002.

d. Model run years

The IPM models the electric power market over the 26-year period 2005 to 2030. Due to the data-intensive processing procedures, the model is run for a limited number of years only. Run years are selected based on analytical requirements and the necessity to maintain a balanced choice of run years throughout the modeled time horizon. EPA selected the following run years for this analysis: 2008, 2010, and 2013.[6] Model run year 2008 was selected based on the assumption that all in-scope facilities will be required to comply with the requirements of the proposed rule during the first five years after promulgation in 2003, i.e., 2004 to 2008. Therefore, 2008 represents the long-term, post-compliance state of the industry. Run year 2013 was selected based on the assumption that facilities costed with a cooling tower (a requirement for some facilities under the two alternative options analyzed with the IPM) would have to comply by the end of the permit term of the first permit issued after promulgation, i.e., 2004 to 2012. As installation of a cooling tower may require the temporary shut-down of the facility (this analysis assumes one month of shut-down time), 2013 would represent the first full, post-compliance year for options requiring cooling towers. Run year 2010 was selected as an additional year during which facilities costed with a cooling tower may experience temporary connection outages during cooling tower installation and connection. (For a description of the assignment of compliance years, see *Chapter B1: Summary of Compliance Costs*).

The model assumes that capital investment decisions are only implemented during run years. Each model run year is mapped to several calendar years such that changes in variable costs, available capacity, and demand for electricity in the years between the run years are partially captured in the results for each model run year. Table B3-2 below identifies the model run years specified for the analysis of the proposed rule and other regulatory options, and the calendar years mapped to each.

[6] The IPM developed output for a total of five model run years 2008, 2010, 2013, 2020, and 2026. Model run years 2020 and 2026 were specified for model balance, while run years 2008, 2010, and 2013 were selected to provide output across the compliance period. Output for 2020 and 2026 was not used in this analysis.

Table B3-2: Model Run Year Mapping	
Run Year	**Mapped Years**
2008	2005-2009
2010	2010-2012
2013	2013-2015
2020	2016-2022
2026	2023-2030

Source: IPM model specification for the Section 316(b) Base Case.

EPA mainly relied on data for 2008 in the analyses of the proposed rule (presented in this chapter) and on data for 2013 in the analyses of the alternative regulatory options (presented in *Chapter B7: Alternative Regulatory Options*).

B3-2.2 Specifications for the Section 316(b) Analysis

The analysis of the proposed Phase II Rule and the other regulatory options analyzed with the IPM required changes in the original specification of the IPM model. Specifically, the base case configuration of the model plants and model run years were revised according to the requirements of this analysis. Both modifications to the existing model specifications are discussed below.

- ***Changes in the Aggregation of Model Plants:*** As noted above, the IPM aggregates individual boilers and generators with similar cost and operational characteristics into model plants. Since the IPM model plants were initially created to support air policy analyses, the original configuration was not appropriate for the section 316(b) analysis. As a result, the steam electric generators at facilities subject to the Phase II Rule were disaggregated from the existing IPM model plants and "run" as individual facilities along with the other existing model plants. This change increased the total number of model plants from 1,390 to 1,777.

- ***Use of Different Model Run Years:*** The original specification of the EPA Base Case 2000 of the IPM uses five model run years chosen based on the requirements of various air policy analyses. As EPA assumed that all facilities subject to the proposed rule and other regulatory options would come into compliance within the first permitting cycle after promulgation in 2003 (i.e., 2004 to 2012), the run years specified for the EPA Base Case 2000 are not of primary interest to this analysis. Therefore, EPA selected different run years for the section 316(b) analysis in order to obtain model output throughout the compliance period (see discussion of run year selection in section B3-2.1.d above). The change in run years and run year mappings are summarized below.

Table B3-3: Modification of Model Run Years			
EPA Base Case 2000 Specification		**Section 316(b) Base Case Specification**	
Run Year	**Run Year Mapping**	**Run Year**	**Run Year Mapping**
2005	2005-2007	2008	2005-2009
2010	2008-2012	2010	2010-2012
2015	2013-2017	2013	2013-2015
2020	2018-2022	2020	2016-2022
2026	2023-2030	2026	2023-2030

Source: IPM model specifications for the EPA Base Case 2000 and the Section 316(b) Base Case.

EPA compared the base case results generated from the two different specifications of the IPM model. The base case results could only be compared for those run years that are common to both base cases, 2010 and 2020. This comparison identified little or no difference in the base case results:

- Base case total production costs (capital, O&M, and fuel) using the revised section 316(b) specifications are higher by 0.4% and 0.1% in the years 2010 and 2020, respectively.
- Early retirements of base case oil and gas steam capacity under the section 316(b) specifications increased by 390 MW. Early retirements of base case nuclear capacity decreased by 429 MW. There is no difference in the early retirement of coal capacity.
- The change in model specifications results in virtually no change in base case coal and gas fuel use.

B3-2.3 Model Inputs

Compliance costs and compliance-related capacity reductions are the primary model inputs in the analysis of section 316(b) regulations. EPA determined compliance costs for each of the 530 facilities subject to the proposed rule and modeled by the IPM.[7] For each facility, compliance costs consist of capital costs (including new wet tower capital costs, intake piping modification capital costs, and condenser upgrade costs for facilities costed with flow reduction technologies), fixed O&M costs, variable O&M costs, and permitting costs (for information on the costing methodology, see the § 316(b) Technical Development Document).[8]

Capital cost inputs into the IPM are expressed in terms of dollars per KW of capacity. The capital costs of compliance reflect the up-front cost of construction, equipment, and capital associated with the installation of required compliance technologies. While IPM uses a single up-front cost as a model input, the model translates this cost into a series of annual payments using a discount rate of 5.34 percent and a capital charge rate of 12 percent for the duration of the book life of the investment (assumed to be 30 years) or the years remaining in the modeling horizon, whichever is shorter.[9] The net present value of this stream of annual capital payments is the model input included as part of the objective function for which the model seeks the least cost solution.

Fixed O&M cost inputs into the IPM are expressed in terms of dollars per KW of capacity per year. ***Variable O&M cost*** inputs are expressed in dollars per MWh of generation.

Capacity reductions consist of an energy penalty and a one-time generator down-time and, for purposes of this analysis, were only applied to facilities costed with flow reduction technologies. ***Energy penalty*** estimates reflect the long-term reduction in capacity due to the on-going operation of compliance technologies and are expressed in terms of a percentage change in capacity. The energy penalty consists of two components: (1) a reduction in unit efficiency due to increased turbine back-pressure and (2) an increase in auxiliary power requirements to operate the cooling tower (e.g., for pumping and fanning). As discussed in *Chapter B1: Summary of Compliance Costs*, EPA's estimate of O&M compliance costs already includes the auxiliary power requirement component of the energy penalty. However, to fully capture the effect of the energy penalty in the market model analysis, the both components of energy penalty needed to be applied. To avoid double-counting of the auxiliary power requirements, EPA reduced the O&M compliance cost input into the IPM by the estimated value of the auxiliary power penalty, using the valuation methodology described in Chapter B1. ***Generator down-time*** estimates reflect the amount of time generators are off-line while compliance technologies are constructed and/or installed and are expressed in weeks. In contrast to the energy penalty, the generator down-time is a one-time event that occurs during the year when a facility complies with the policy option (for a discussion of how EPA estimated compliance years, see *Chapter B1: Summary of Compliance Costs*). Capacity reductions were only assigned to facilities costed with flow reduction technologies. Therefore, no facilities experience a capacity reduction (energy penalty or one-time shut down) under the proposed rule.

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[7] Of the 539 surveyed facilities subject to the section 316(b) Phase II Rule, nine are not modeled in the IPM. Three facilities are in Hawaii, one is in Alaska. Neither state is represented in the IPM. One facility is identified as an "Unspecified Resource" and does not report on any EIA forms. Four facilities are on-site facilities that do not provide electricity to the grid. The 530 in-scope facilities modeled by the IPM were weighted to account for facilities not sampled and facilities that did not respond to the EPA's industry survey and thus represent a total of 540 facilities industry-wide. The results for Phase II facilities in the remainder of this chapter, except where noted, are based on the 540 weighted facilities.

[8] No facilities under the proposed rule were costed with flow reduction technologies. However, 51 facilities were costed with flow reduction technology under the "Closed-loop, Recirculating Wet Cooling based on Waterbody type and Intake Capacity" Option (waterbody/capacity-based option) and 417 facilities were costed with flow reduction technology under the "Closed-loop, Recirculating Wet Cooling Everywhere" Option (all cooling towers option) (see discussion in *Chapter B7: Alternative Regulatory Options*).

[9] The capital charge rate is a function of capital structure (debt/equity shares of an investment), pre-tax debt rate (or interest cost), debt life, post-tax return on equity, corporate income tax, depreciation schedule, book life of the investment, and other costs including property tax and insurance. The discount rate is a function of capital structure, pre-tax debt rate, and post-tax return on equity.

The IPM operates at the boiler level. It was therefore necessary to distribute facility-level costs across affected boilers. EPA used the following methodology:

- Steam electric generators operating at each of the 530 modeled section 316(b) facilities were identified using data from Forms EIA-860A and 860B (1998 and 1999).
- Generator-specific design intake flows were obtained from Form EIA-767 (1998).[10]
- Facility-level compliance costs were distributed across each facility's steam generators. For facilities with available intake flow data, this distribution was based on each generator's proportion of total design intake volume; for facilities without available intake flow, this distribution was based on each generator's proportion of total steam electric capacity.
- Generator-level compliance costs were aggregated to the boiler level based on the EPA's Base Case 2000 cross-walk between boilers and generators.

B3-2.4 Model Outputs

The IPM generates a series of outputs on different levels of aggregation (boiler, model plant, region, and nation). The economic analysis for the Phase II Rule used a subset of the available IPM output. For each model run (base case and each analyzed policy option) and for each model run year (2008, 2010, 2013, and 2020) the following model outputs were generated:

- ***Capacity*** – Capacity is a measure of the ability to generate electricity. This output measure reflects the summer net dependable capacity of all generating units at the plant. The model differentiates between existing capacity, new capacity additions, and existing capacity that has been repowered.[11]

- ***Generation*** – The amount of electricity produced by each plant that is available for dispatch to the transmission grid ("net generation")..

- ***Energy Revenue*** – Revenues from the sale of electricity to the grid.

- ***Capacity Revenue*** – Revenues received by facilities operating in hours where the price of energy exceeds the variable production costs of generation for the next unit to be dispatched at that price in order to maintain reliable energy supply in the short run. At these peak hours, the price of energy includes a premium which reflects the cost of the required reserve margin and serves to stimulate investment in the additional capacity required to maintain a long run equilibrium in the supply and demand for capacity.

- ***Fuel Costs*** – The cost of fuel consumed in the generation of electricity.

- ***Variable Operation and Maintenance Costs*** – Non-fuel O&M costs that vary with the level of generation, e.g., cost of consumables, including water, lubricants, and electricity.

- ***Fixed Operation and Maintenance Costs*** – O&M costs that do not vary with the level of generation, e.g., labor costs and capital expenditures for maintenance.

- ***Capital Costs*** – The cost of construction, equipment, and capital. In the base case, capital costs at existing facilities are associated with investment in new equipment, e.g., the replacement of a boiler or condenser, or the repowering of the plant. In the post-compliance cases, this cost includes retrofitting existing plants with compliance technologies to meet the requirements of the proposed rule and the alternative regulatory options.

- ***Energy Price*** – The average annual price received for the sale of electricity.

- ***Capacity Price*** – The premium over energy prices received by facilities operating in peak hours during which system load approaches available capacity. The capacity price is the premium required to stimulate new market

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[10] This information is provided in Schedule IV - Generator Information, Question 3.A (Design flow rate for the condenser at 100% load). Design intake flow data at the generator level is not available for nonutilities nor for those utility owned plants with a steam generating capacity less than 100MW. Generator-level design intake flow data were not available for 50 of the 530 modeled facilities.

[11] Repowering in the IPM consists of converting of oil/gas capacity to combined-cycle capacity.

entrants to construct additional capacity, cover costs, and earn a return on their investment. This price manifests as short term price spikes during peak hours and, in long-run equilibrium, need be only so large as is required to justify investment in new capacity.

- ***Early Retirements*** – The IPM models two types of plant closures: closures of nuclear plants as a result of license expiration and economic closures as a result of negative net present value of future operation.[12] This analysis only considers economic closures in assessing the impacts of the proposed rule and other regulatory options. However, cases where a nuclear facility decides to renew its license in the base case but does not renew its license in the post-compliance case for a given policy option are also considered economic closures and an impact of that policy option.

B3-3 ECONOMIC IMPACT ANALYSIS METHODOLOGY

The IPM was used to identify changes to economic and operational characteristics such as capacity, generation, revenue, cost of generation, and electricity prices associated with the proposed Phase II Rule and alternative regulatory options. EPA identified changes resulting from each policy option by comparing it to the base case (i.e., the model run in the absence of section 316(b) Phase II regulations).[13] The outputs presented in the previous section were used to estimate the economic impacts of each regulatory option. EPA developed impact measures at two analytic levels: (1) the market as a whole and (2) the subset of in-scope Phase II facilities. Both analyses were conducted by NERC region. In both cases, the impacts of each option are defined as the difference between the model output for the base case scenario and the post-compliance scenario. The following subsections describe the impact measures used for the two levels of analysis.

B3-3.1 Market-level Impact Measures

The market-level analysis evaluates regional changes as a result of the proposed rule and the alternative regulatory options. Seven main measures are analyzed:

- ***(1) Changes in available capacity:*** This measure analyzes changes in the capacity available to generate electricity. A long-term reduction in availability may be the result of the energy penalty associated with the installation of recirculating systems, and of partial or full closures of plants subject to the rule. In the short term, temporary plant shut-downs for the installation of cooling towers may lead to reductions in available capacity. When analyzing changes in available capacity, EPA distinguished between existing capacity, new capacity additions, and repowering additions.

- ***(2) Changes in generation:*** This measure considers the amount of electricity generated. At a regional level, long-term changes in generation may be the result of plant closures, energy penalties, or a change in the amount of electricity traded between regions. In the short term, temporary plant shut-downs to install recirculating systems may lead to reductions in generation. At the national level, the demand for electricity does not change between the base case and the analyzed policy options (generation within the regions is allowed to vary). However, demand for electricity does vary across the modeling horizon according to the model's underlying electricity demand growth assumptions.

- ***(3) Changes in revenues:*** This measure considers the revenues realized by all facilities in the market. A change in revenues could be the result of a change in generation and/or the price of electricity.

- ***(4) Changes in variable production costs:*** This measure considers the regional change in average variable production cost per MWh. Variable production costs include fuel costs and other variable O&M costs but exclude

[12] Nuclear plants are evaluated for economic viability at the end of their license term. Nuclear units that, at age 30, did not make a major maintenance investment, are provided with a 10-year life extension, if they are economically viable. These same units may subsequently undertake a 20-year re-licensing option at age 40. Nuclear units that already had made a maintenance investment are provided with a 20-year re-licensing option at age 40, if they are economically viable. All nuclear units are ultimately retired at age 60.

[13] EPA conducted model runs based on different electricity demand assumptions: (1) a case using EPA's electricity demand assumptions and (2) a case using Annual Energy Outlook (AEO) electricity demand assumptions. The analyses presented in this chapter are based on EPA's electricity demand assumptions. The appendix to *Chapter B7: Alternative Regulatory Options* presents a discussion of the two different assumptions, the results of one alternative regulatory option using the AEO electricity demand assumptions, and a comparison of the differences in results between the AEO assumptions and the EPA assumptions.

fixed O&M costs and capital costs. Production cost per MWh is a primary determinant of how often a power plant's units are dispatched.

- ***(5) Changes in fuel costs:*** This measure considers a subset of the production costs included in the previous measure: fuel costs. Fuel costs generally account for the single largest share of production costs.

- ***(6) Changes in the price of electricity:*** This measure considers changes in regional prices as a result of the proposed rule. In the long term, electricity prices may change as a result of increased production costs of the Phase II facilities. In the short-term, price increases may be higher if large power plants have to temporarily shut down to construct and/or install recirculating systems. This analysis considers changes in both energy prices and capacity prices.

- ***(7) Plant closures:*** Only plants that are projected to remain operational in the base case but are closures in the post-compliance case are considered a closure as the result of the rule. An option may result in partial (i.e., unit) or full plant closures. An option may also result in avoided closures if a facility's compliance costs are low relative to other affected facilities. An avoided closure is a facility that would close in the base case but operates in the post-compliance case. At the market-level, the closure analysis considers the amount of capacity retired early, but not the number of retired facilities.

B3-3.2 Facility-level Impact Measures (In-scope Facilities Only)

EPA used the IPM results to analyze impacts on Phase II facilities at two levels: (1) potential changes in the economic and operational characteristics of the group of Phase II facilities and (2) potential changes to individual facilities within the group of Phase II facilities.

a. Group of Phase II facilities

The analysis of the group of Phase II facilities is largely similar to the market-level analysis described in Section B3-3.1 above, except that the base case and policy option totals only include the economic activities of the steam-electric generating units of the 540 in-scope Phase II facilities represented by the model. In addition, a few measures differ: (1) new capacity additions and prices are not relevant at the facility level, (2) repowering changes were not explicitly analyzed at the facility level, and (3) an additional measure, facilities that are not dispatched, is analyzed in this section but was not relevant at the market level. The following are the measures evaluated for the group of Phase II facilities:

- ***(1) Changes in available capacity:*** This measure considers the capacity available at the 540 Phase II facilities. A long-term reduction in availability may be the result of the energy penalty associated with the installation of recirculating systems, and of partial or full closures of plants subject to the rule. In the short term, temporary plant shut-downs for the installation of cooling towers may lead to reductions in available capacity.

- ***(2) Changes in generation:*** This measure considers the generation at the 540 Phase II facilities. Long-term changes in generation may be the result of plant closures, energy penalties, or a less frequent dispatch of a plant due to higher production cost as a result of the policy option. In the short term, temporary plant shut-downs may lead to reductions in generation at some of the 540 Phase II facilities. For some Phase II facilities, the proposed rule may lead to an increase in generation if their compliance costs are low relative to other affected facilities.

- ***(3) Changes in revenues:*** This measure considers the revenues realized by the 540 Phase II facilities. A change in revenues could be the result of a change in generation and/or the price of electricity. For some modeled 316(b) facilities, the proposed rule may lead to an increase in revenues if their generation increases as a result of the rule, or if the rule leads to an increase in electricity prices.

- ***(4) Changes in variable production costs:*** This measure considers the plant-level change in the average annual variable production cost per MWh. Variable production costs include fuel costs and other variable O&M costs but exclude fixed O&M costs and capital costs.

- ***(5) Changes in fuel costs:*** This measure considers a subset of the production costs included in the previous measure: fuel costs. Fuel costs generally account for the single largest share of production costs.

- ***(6) Plant closures:*** Only plants that are projected to remain operational in the base case but are closures in the post-compliance case are considered a closure as the result of the rule. An option may result in partial (i.e., unit) or full plant closures. An option may also result in avoided closures if a facility's compliance costs are low relative to other affected facilities. An avoided closure is a facility that would close in the base case but operate in the post-compliance case. At the facility-level, both the number of closure facilities and their capacity are analyzed.

- ***(7) Non-dispatch facilities:*** This measures identifies Phase II facilities that do not generate electricity but are earning capacity revenues. These are facilities that do not retire but are also not dispatched. These facilities provide a portion of the spinning reserves necessary for system reliability. An increase in production costs may lead additional facilities to become non-dispatch facilities. Conversely, compliance costs that are relatively lower than those of other competing facilities may cause a non-dispatch facility in the base case to be dispatched under a policy option.

b. Individual Phase II facilities

To assess potential distributional impacts among individual Phase II facilities, EPA analyzed facility-specific changes to a number of key measures. For each measure, EPA determined the number of Phase II facilities that experience an increase or a reduction, respectively, within two ranges: 0 to 1 percent, and 1 percent or more.[14] EPA conducted this analysis for the following measures:

- ***(1) Changes in capacity utilization:*** Capacity utilization is defined as a unit's actual generation divided by its potential generation, if it ran 100 percent of the time (i.e., generation / (capacity * 365 days * 24 hours)). This measure indicates how frequently a unit is dispatched and earns energy revenues for its owner.

- ***(2) Changes in generation:*** See explanation in subsection a. above.

- ***(3) Changes in revenues:*** See explanation in subsection a. above.

- ***(4) Changes in variable production costs:*** See explanation in subsection a. above.

- ***(5) Changes in fuel costs:*** See explanation in subsection a. above.

- ***(6) Changes in operating income:*** Operating income is defined as revenues minus production cost. Operating income is an indicator of profitability and represents the amount of money available to cover the firm's non-production costs. Operating income of Phase II facilities may decrease as a result of reductions in revenues and/or increases in production costs.

B3-4 Analysis Results for the Proposed Rule

EPA was not able to execute the market model analysis with an analytic option that completely matches the proposed rule's specifications. Due to the lead time required to run an integrated electricity market model, EPA first completed an electricity market model analysis of two options with costs higher than those of the proposed option: (1) the waterbody/capacity-based option and (2) the all cooling towers option (the results of these two options are presented in *Chapter B7: Alternative Regulatory Options*). Both of the analyzed options are more stringent in aggregate than the proposed rule and provide a ceiling on the proposed rule's potential economic impacts. Because of limited time after the final definition of the proposed rule, EPA was unable to rerun the IPM model. As a result, EPA adopted a two-step approach for the analysis of potential impacts from the proposed Phase II Rule that uses the model outputs from the waterbody/capacity-based option:

- First, EPA identified that for certain regional electricity markets that do not have any facilities costed with a closed-cycle recirculating cooling water system, the waterbody/capacity-based option, as analyzed, matches the technology compliance requirements of the proposed rule.[15] These are the North American Electric Reliability Council (NERC) regions that do not border oceans and estuaries: ECAR, MAIN, MAPP, SPP. Accordingly, EPA was able to

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[14] For the two alternative options analyzed in *Chapter B7: Alternative Regulatory Options*, EPA used three ranges: 0 to 1 percent, 1 to 3 percent, and 3 percent or more.

[15] While the compliance requirements are identical under the proposed rule and the alternative waterbody/capacity-based option, permitting costs associated with the proposed rule are higher than those for the alternative option analyzed using the IPM. The cost differential averages approximately 30 percent of total compliance costs associated with the alternative option. Despite the higher permitting costs, EPA concludes that the results of the alternative analysis are representative of impacts that could be expected under the proposed rule.

interpret the results of the IPM analysis for the waterbody/capacity-based option for these four NERC regions as representative of the proposed rule in these regions.

- Second, EPA determined that while the waterbody/capacity-based option, as analyzed in the IPM, matches the technology specifications of the proposed rule for the four regions discussed above, this is not the case for the other six NERC regions: ERCOT, FRCC, MAAC, NPCC, SERC, and WSCC. Under the waterbody/capacity-based option, some facilities in these regions were costed with more stringent and costly compliance requirements, including recirculating wet cooling towers, than would be required by the proposed rule. As a result, the IPM waterbody/capacity-based option overstates the impacts of the expected rule in these remaining six regions. To provide an alternative approach to estimating the rule's impacts in these regions, EPA compared the four NERC regions explicitly analyzed in the IPM analysis and the other six NERC regions in terms of characteristics relevant to the determination of the rule's impacts. EPA found no material differences between the two groups of regions in (1) the percentage of total base case capacity subject to the proposed rule, (2) the average annualized compliance costs of the proposed rule per MWh of generation, and (3) the distribution of compliance requirements of the proposed rule (see Table B3-4 below). EPA therefore concludes that the results for the four regions would be representative of the other NERC regions as well.

Table B3-4: Comparison of Compliance Requirements by NERC Region - 2008

NERC Region	Percent of Total Capacity Subject to the Rule	Total Annualized Compliance Cost per MWh Generation ($2001)	Percentage of In -Scope Facilities Subject to Each Compliance Requirement				
			Number of Phase II Facilities	Fine Mesh Traveling Screen w/ Fish Handling	Fine-Mesh Traveling Screen	Fish Handling and Return System	None
Four Analyzed NERC Regions							
ECAR	66.5%	$0.05	99	32.4%	7.1%	23.9%	36.6%
MAIN	60.9%	$0.04	49	30.6%	6.1%	22.7%	40.7%
MAPP	42.1%	$0.04	42	9.5%	7.1%	28.5%	54.8%
SPP	40.7%	$0.03	32	12.6%	0.0%	46.9%	40.5%
Average	**57.1%**	**$0.04**		**24.8%**	**5.8%**	**27.8%**	**41.5%**
Other Six NERC Regions							
ERCOT	57.8%	$0.04	51	2.0%	11.8%	60.8%	25.5%
FRCC	49.8%	$0.07	30	40.0%	13.3%	16.7%	30.0%
MAAC	50.7%	$0.06	43	26.2%	19.1%	28.8%	25.9%
NPCC	49.6%	$0.08	54	22.1%	34.2%	16.5%	27.1%
SERC	53.8%	$0.03	95	16.8%	7.4%	31.6%	44.2%
WSCC	18.3%	$0.02	33	52.9%	3.0%	16.6%	27.5%
Average	**43.6%**	**$0.04**		**22.8%**	**14.6%**	**30.3%**	**32.3%**
Average of All NERC Regions	**47.7%**	**$0.04**		**23.6%**	**10.9%**	**29.3%**	**0.3619367**

Source: U.S. EPA, 2000; U.S. EPA analysis, 2002.

Table B3-4 indicates that, on average, the ***percentage of capacity subject to the proposed rule*** is slightly higher in the four analyzed NERC regions compared to the other six regions. Everything else being equal, the higher the percentage of capacity subject to the rule, the greater the likelihood that the rule would affect production costs and electricity prices at a regional level. In addition, the ***average annualized compliance costs per MWh of generation*** for the four NERC regions, 4 cents per MWh, is identical to that of the other six NERC regions. Again, everything else being equal, the higher the compliance cost per MWh, the greater the likelihood that the rule would affect production costs and electricity prices at a regional level. Finally, the ***distribution of compliance requirements*** is similar for the two groups of regions. The four analyzed regions have a slightly higher percentage of in-scope facilities costed with the most costly compliance technology, fine mesh traveling screens with fish handling systems, than the other six regions. Conversely, the six regions have a higher percentage of facilities costed with fine mesh screens, the second most costly compliance technology. The six regions also have a lower percentage of facilities that are costed with no compliance technologies. Everything else being equal, the more facilities costed with costly compliance technology, the higher the impacts that could be expected for Phase II facilities as a group and for individual Phase II facilities.

Based on this comparison and the limited amount of electricity exchanges between regions modeled in IPM,[16] EPA concluded that the analysis of impacts under the proposed rule for the four NERC regions is representative of likely impacts in the other six NERC regions.

The remainder of this section presents the results of the economic impact analysis of the proposed rule for the four NERC regions for which the technology requirements under the waterbody/capacity-based option are identical to those of the proposed rule: ECAR, MAIN, MAPP, SPP. The analysis is based on IPM output for the base case and proposed rule for model run year 2008. Results are presented at the market level and the Phase II facility level.

B3-4.1 Market Analysis

This section presents the results of the IPM analysis for all facilities modeled by the IPM. The results in this section include facilities that are in-scope and facilities that are out-of-scope of the proposed Phase II Rule. As stated above, EPA concluded that results for the four NERC regions presented below are representative of likely impacts in the other six NERC regions.

Table B3-5 presents the market-level impact measures discussed in section B3-3.1 above: (1) Capacity changes, (2) generation changes, (3) revenue changes, (4) variable production cost changes, (5) fuel cost changes, (6) electricity price changes, and (7) plant closures. For each measure, the table presents the results for the base case and the proposed rule, the absolute difference between the two cases, and the percentage difference.

Table B3-5: Market Level Impacts of the Proposed Rule (Four NERC Regions; 2008)

Economic Measures[a]	Base Case	Proposed Rule	Difference	% Change
East Central Area Reliability Coordination Agreement (ECAR)				
(1) Total Domestic Capacity (MW)	118,390	118,570	180	0.2%
(1a) Existing	110,080	110,080	0	0.0%
(1b) New Additions	8,310	8,490	180	2.2%
(1c) Repowering Additions	0	0	0	0.0%
(2) Total Generation (GWh)	649,140	649,140	0	0.0%
(3) Total Revenues (Million, $2001)	$23,830	$23,850	$20	0.1%
(4) Variable Production Costs ($2001/MWh)	$12.53	$12.53	$0.00	0.0%
(5) Fuel Costs ($2001/MWh)	$10.11	$10.11	$0.00	0.0%
(6a) Energy Prices ($2001/MWh)	$22.58	$22.56	($0.02)	-0.1%
(6b) Capacity Prices ($2001/KW/yr)	$77.67	$77.86	$0.19	0.2%
(7) Closures – Capacity	0	0	0	0.0%

[16] Significant amounts of electricity exchanged between regions could limit the findings from the NERC region comparison, because the four analyzed regions may have benefitted from the higher compliance costs of the other six regions in the analyzed regulatory alternative. However, base case transmission from the four analyzed regions to the other six regions range from 3.5 to 6.7 percent of total generation, while transmission from the other six regions to the four analyzed ones ranges from 0 to 0.2 percent. In the post-compliance case, the change in transmissions of all regions is 0.2 percent or less.

Table B3-5: Market Level Impacts of the Proposed Rule (Four NERC Regions; 2008)				
Economic Measures[a]	**Base Case**	**Proposed Rule**	**Difference**	**% Change**
Mid-America Interconnected Network (MAIN)				
(1) Total Domestic Capacity (MW)	60,230	60,210	-20	0.0%
(1a) Existing	53,690	53,680	-10	0.0%
(1b) New Additions	6,540	6,530	-10	-0.2%
(1c) Repowering Additions	0	0	0	0.0%
(2) Total Generation (GWh)	284,920	284,860	-60	0.0%
(3) Total Revenues (Million, $2001)	$11,120	$11,120	$0	0.0%
(4) Variable Production Costs ($2001/MWh)	$12.29	$12.29	$0.00	0.0%
(5) Fuel Costs ($2001/MWh)	$10.25	$10.25	$0.00	0.0%
(6a) Energy Prices ($2001/MWh)	$22.54	$22.55	$0.01	0.0%
(6b) Capacity Prices ($2001/KW/yr)	$78.15	$78.18	$0.02	0.0%
(7) Closures – Capacity	0	0	0	0.0%
Mid-Continent Area Power Pool (MAPP)				
(1) Total Domestic Capacity (MW)	35,470	35,470	0	0.0%
(1a) Existing	32,710	32,710	0	0.0%
(1b) New Additions	2,760	2,760	0	0.0%
(1c) Repowering Additions	0	0	0	0.0%
(2) Total Generation (GWh)	179,110	179,170	60	0.0%
(3) Total Revenues (Million, $2001)	$6,710	$6,700	($10)	-0.1%
(4) Variable Production Costs ($2001/MWh)	$11.67	$11.68	$0.01	0.0%
(5) Fuel Costs ($2001/MWh)	$9.64	$9.65	$0.01	0.1%
(6a) Energy Prices ($2001/MWh)	$22.25	$22.20	($0.05)	-0.2%
(6b) Capacity Prices ($2001/KW/yr)	$77.79	$77.74	($0.05)	-0.1%
(7) Closures – Capacity	0	0	0	0.0%
Southwest Power Pool (SPP)				
(1) Total Domestic Capacity (MW)	49,110	49,110	0	0.0%
(1a) Existing	48,950	48,950	0	0.0%
(1b) New Additions	160	160	0	0.0%
(1c) Repowering Additions	0	0	0	0.0%
(2) Total Generation (GWh)	217,670	217,750	80	0.0%
(3) Total Revenues (Million, $2001)	$8,440	$8,440	$0	0.0%
(4) Variable Production Costs ($2001/MWh)	$14.43	$14.43	$0.01	0.1%
(5) Fuel Costs ($2001/MWh)	$12.52	$12.52	$0.01	0.1%
(6a) Energy Prices ($2001/MWh)	$25.00	$24.99	($0.01)	0.0%
(6b) Capacity Prices ($2001/KW/yr)	$61.24	$61.24	$0.00	0.0%
(7) Closures – Capacity	0	0	0	0.0%

[a] Total capacity, existing capacity, total generation, and total revenues have been rounded to nearest 10.

Source: IPM analysis: model runs for Section 316(b) Base Case and Waterbody/Capacity-Based Option.

The results presented in Table B3-5 show that the proposed rule would not lead to significant changes in any of the analyzed economic measures in any of the four regions. This finding is not surprising as the requirements of the proposed Phase II Rule are very inexpensive compared to the overall production costs in the regions (Table B3-4 indicates that the average cost of compliance per MWh of generation for these four regions is $0.04 as compared to an average variable production cost of $12.73). ECAR is projected to install 180 MW, or 2.2 percent, more new capacity under the proposed rule. However, this additional capacity represents only 0.2 percent of total capacity in the region. All other measures in all other regions change by 0.2 percent or less as a result of the proposed rule, with a majority having zero change. Based on these results, EPA concludes that there would be no energy effects from the proposed Phase II Existing Facilities Rule in these regions.

B3-4.2 Analysis of Phase II Facilities

This section presents the results of the IPM analysis for the Phase II facilities that are modeled by the IPM. Of the 540 Phase II facilities, 226 are located in the four analyzed regions. Three of these 226 facilities are identified by the IPM as baseline closures (two are located in MAIN, one is located in MAPP) and are therefore not represented in these results. Except where noted, the results in this section therefore reflect the 223 non-closure Phase II facilities modeled by the IPM.

EPA used the IPM results to analyze two potential facility-level impacts of the proposed section 316(b) Phase II Rule: (1) potential changes in the economic and operational characteristics of the group of Phase II facilities and (2) potential changes to individual facilities within the group of Phase II facilities. It should be noted that the results of both analyses only include the steam electric components of the Phase II facilities and thus do not provide complete measures for in-scope facilities that also operate non-steam electric generation, which are not subject to this rule.

a. Group of Phase II facilities

The analysis of performed for the group of Phase II facilities is similar to the market level analysis described above but is limited to facilities subject to the requirements of the section 316(b) rule. Table B3-6 presents the impact measures for the group of Phase II facilities discussed in section B3-3.2 above: (1) Capacity changes, (2) generation changes, (3) revenue changes, (4) variable production cost changes, (5) fuel cost changes, (6) plant closures, and (7) non-dispatch facilities. For each measure, the table presents the results for the base case and the proposed rule, the absolute difference between the two cases, and the percentage difference.

Table B3-6: Impacts on the Phase II Facilities of the Proposed Rule (Four NERC Regions; 2008)

Economic Measures[a]	Base Case	Proposed Rule	Difference	% Change
East Central Area Reliability Coordination Agreement (ECAR)				
(1) Total Capacity (MW)	78,710	78,710	0.00	0.0%
(2) Total Generation (GWh)	515,020	515,030	10.00	0.0%
(3) Revenues (Million, $2001)	$17,650	$17,650	$0.00	0.0%
(4) Variable Production Costs ($2001/MWh)	$12.34	$12.34	$0.00	0.0%
(5) Fuel Costs ($2001/MWh)	$9.94	$9.94	$0.00	0.0%
(6a) Closures – Number of Facilities	0	0	0.00	0.0%
(6b) Closures – Capacity	0	0	0.00	0.0%
(7a) Non-Dispatched Facilities – Number	2	2	0.00	0.0%
(7b) Non-Dispatched Facilities – Capacity	191	191	0.00	0.0%

Table B3-6: Impacts on the Phase II Facilities of the Proposed Rule (Four NERC Regions; 2008)

Economic Measures[a]	Base Case	Proposed Rule	Difference	% Change
Mid-America Interconnected Network (MAIN)				
(1) Total Capacity (MW)	36,700	36,700	0.00	0.0%
(2) Total Generation (GWh)	226,360	226,350	-10.00	0.0%
(3) Revenues (Million, $2001)	$7,890	$7,890	$0.00	0.0%
(4) Variable Production Costs ($2001/MWh)	$11.74	$11.74	$0.00	0.0%
(5) Fuel Costs ($2001/MWh)	$9.55	$9.55	$0.00	0.0%
(6a) Closures – Number of Facilities	0	0	0.00	0.0%
(6b) Closures – Capacity	0	0	0.00	0.0%
(7a) Non-Dispatched Facilities – Number	2	2	0.00	0.0%
(7b) Non-Dispatched Facilities – Capacity	2,757	2,757	0.00	0.0%
Mid-Continent Area Power Pool (MAPP)				
(1) Total Capacity (MW)	14,920	14,920	0.00	0.0%
(2) Total Generation (GWh)	103,430	103,470	40.00	0.0%
(3) Revenues (Million, $2001)	$3,420	$3,420	$0.00	0.0%
(4) Variable Production Costs ($2001/MWh)	$11.78	$11.78	$0.00	0.0%
(5) Fuel Costs ($2001/MWh)	$9.84	$9.85	$0.00	0.0%
(6a) Closures – Number of Facilities	0	0	0.00	0.0%
(6b) Closures – Capacity	0	0	0.00	0.0%
(7a) Non-Dispatched Facilities – Number	6	6	0.00	0.0%
(7b) Non-Dispatched Facilities – Capacity	326	326	0.00	0.0%
Southwest Power Pool (SPP)				
(1) Total Capacity (MW)	19,990	19,990	0.00	0.0%
(2) Total Generation (GWh)	112,250	112,350	100.00	0.1%
(3) Revenues (Million, $2001)	$3,930	$3,930	$0.00	0.0%
(4) Variable Production Costs ($2001/MWh)	$13.32	$13.34	$0.01	0.1%
(5) Fuel Costs ($2001/MWh)	$11.07	$11.09	$0.01	0.1%
(6a) Closures – Number of Facilities	0	0	0.00	0.0%
(6b) Closures – Capacity	0	0	0.00	0.0%
(7a) Non-Dispatched Facilities – Number	8	8	0.00	0.0%
(7b) Non-Dispatched Facilities – Capacity	1,857	1,857	0.00	0.0%

[a] Total capacity, total generation, and revenues have been rounded to the closest 10.

Source: IPM analysis: model runs for Section 316(b) Base Case and Waterbody/Capacity-Based Option.

The results presented in Table B3-6 show that the proposed rule would not lead to significant changes in the performance of the 223 Phase II facilities as evaluated by the seven measures. The rule would cause no early plant closures and would not increase the number of Phase II facilities that are not dispatched. In all analyzed NERC regions, except for SPP, none of the measures experiences any change as a result of the rule. In SPP, generation, variable productions costs, and fuel costs change minimally, 0.1 percent.

b. Individual Phase II facilities

The analysis in the previous section showed that the group of Phase II facilities as a whole would not experience economic impacts under the proposed rule. However, it is possible that there would be shifts in economic performance among individual facilities subject to this rule. To examine the range of possible impacts to individual Phase II facilities, EPA analyzed facility-specific changes in (1) capacity utilization, (2) generation, (3) revenues, (4) variable production costs, (5) fuel costs, and (6) operating income. Table B3-7 presents the 223 Phase II facilities located in the four analyzed NERC regions by category of change for each economic measure.

Table B3-7: Number of Individual Phase II Facilities with Operational Changes (Four NERC Regions; 2008)

Economic Measures[a]	Reduction		Increase		No Change
	0-1%	> 1%	0-1%	> 1%	
(1) Change in Capacity Utilization	2	0	2	1	218
(2) Change in Generation	2	0	1	2	218
(3) Change in Revenues	56	0	44	2	121
(4) Change in Variable Production Costs	0	0	27	0	178
(5) Change in Fuel Costs	2	0	43	2	158
(6) Change in Operating Income	66	0	58	1	98

[a] For all measures, the percentages used to assign facilities to impact categories have been rounded to the nearest 10th of a percent.

[b] Of the 223 Phase II facilities located in the four NERC regions, 18 facilities had zero generation and zero fuel costs in either the base case or post-compliance scenario. It was therefore not possible to calculate the change in variable production costs or the change in fuel costs per MWh for these facilities. As a result, the number of facilities adds up to 205 instead of 223 for these two measures.

Source: IPM analysis: model runs for Section 316(b) Base Case and Waterbody/Capacity-Based Option.

Table B3-7 shows that most of the Phase II facilities in the four analyzed NERC regions experience very little changes in economic activity as a result of this rule. No facility experiences a decrease in generation, capacity utilization, revenues, or operating income, or an increase in production costs of more than one percent. These findings, together with the findings from the comparison of compliance costs and requirements across all regions above, further confirm EPA's conclusion that the proposed rule would not result in economic impacts to Phase II facilities located in the four analyzed NERC regions.

B3-5 Summary of Findings

Based on the results presented in sections B3-4.1 and B3-4.2, EPA concludes the proposed rule will have little or no impact on the electricity markets in any of the four analyzed regions, the group of Phase II facilities, or individual Phase II facilities. The analyses at the market and the Phase II facility level have shown that the rule would lead to no significant changes in any of the economic measures examined by EPA.

Given EPA's earlier noted finding of no material differences in important characteristics relevant to rule impacts between the four analyzed NERC regions and the other six NERC regions, EPA concludes that the finding of no significant impact for these four regions could be extended to the remaining six regions. As a result, EPA concludes that the proposed rule will not pose significant impacts in any NERC region.

B3-6 Uncertainties and Limitations

There are uncertainties associated with EPA's analysis of the electric power market and the economic impacts of the proposed Phase II Rule and alternative regulatory options. These uncertainties stem from two main issues: (1) the specification of the policy options analyzed by the IPM and (2) modeling limitations of the IPM.

Specification of policy options: Due to limited time after the final definition of the proposed option, EPA was not able to use the IPM to analyze a regulatory option that completely matches the proposed rule's specifications. Rather, EPA employed a methodology that used the results of a previously completed analysis of the waterbody/capacity-based option, an option with more costly and stringent compliance requirements, to assess the impacts of the proposed rule. The following limitations result from the use of these results to represent the impacts associated with the proposed rule:

- *Extrapolation of results from four regions to the national level:* EPA identified four regional electricity markets (NERC regions) for which the compliance technology requirements under the waterbody/capacity-based option match those of the proposed rule. EPA assumed that the results of the IPM analysis of the more stringent option are representative of the proposed rule in these regions. The six NERC regions for which the compliance technology requirements under the proposed rule are different from the waterbody/capacity-based option were subsequently compared to the four NERC regions with regard to characteristics relevant to the determination of impacts. This comparison revealed no material differences between the two groups of regions. Based on this comparison, EPA concluded that the results for the four regions would be representative of potential impacts for all regions. While EPA recognizes that using the results from four regional markets to represent national impacts introduces some uncertainty, EPA believes this approach to be reasonable given the similarities revealed by the comparison of NERC regions.

- *Difference in permitting costs in four regional markets:* While the compliance technology requirements in the four analyzed NERC regions are identical under the proposed rule and the waterbody/capacity-based option, permitting costs associated with the proposed rule are higher than those for the alternative option. The cost differential averages approximately 30 percent of total compliance costs associated with the alternative option. As a result, EPA's analysis may underestimate facility and market level impacts associated with the proposed rule. However, given the very low absolute costs of the proposed rule, EPA concludes that the results of the alternative analysis are representative of impacts that could be expected under the proposed rule.

Modeling limitations of the IPM: Additional uncertainty is introduced by the IPM modeling framework. Specifically, the IPM assumes that demand at the national level and imports from Canada and Mexico would not change between the base case and the analyzed policy options (generation within the regions is allowed to vary). Under the EPA Base Case 2000 specification, the ***demand for electricity*** is based on the AEO 2001 forecast adjusted to account for demand reductions resulting from implementation of the Climate Change Action Plan (CCAP). The IPM model, as specified for this analysis, does not capture changes in demand that may result from electricity price increases associated with the proposed rule and alternative regulatory options. While this constraint may overestimate total demand in policy options that have high compliance cost and that may therefore lead to significant price increases, EPA believes that it does not affect the results analyzed in support of the proposed rule. As described in Section B3-4 above, the price increases associated with the proposed rule are minimal. EPA therefore concludes that the assumption of inelastic demand-responses to changes in prices is reasonable. In addition, all things being equal, holding generation fixed would result in conservative estimates of production costs and electricity prices because more costly facilities remain economically viable longer to serve load that does not decrease in response to higher prices. Similarly, holding ***international imports*** fixed would provide a conservative estimate of production costs and electricity prices, because imports are not subject to the rule and may therefore become more competitive relative to domestic capacity, displacing some of the more expensive domestic generating units. However, EPA concludes that fixed imports do not materially affect the results of the analyses. Only four of the ten NERC regions import electricity (ECAR, MAPP, NPCC, and WSCC) and the level of imports compared to domestic generation in each of these regions is very small (0.03 percent in ECAR, 2.4 percent in MAPP, 5.6 percent in NPCC, and 1.5 in WSCC).

REFERENCES

U.S. Environmental Protection Agency (U.S. EPA). 2000. Section 316(b) Industry Survey. *Detailed Industry Questionnaire: Phase II Cooling Water Intake Structures* and *Industry Short Technical Questionnaire: Phase II Cooling Water Intake Structures,* January, 2000 (OMB Control Number 2040-0213). *Industry Screener Questionnaire: Phase I Cooling Water Intake Structures*, January, 1999 (OMB Control Number 2040-0203).

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Appendix to Chapter B3

Introduction

This appendix presents additional, more detailed information on EPA's research to identify models suitable for analysis of environmental policies that affect the electric power industry. In addition, this appendix presents a comparison of the specifications of the EPA Base Case 2000 and its predecessor Base Case specifications.

Chapter Contents

B3-A.1 Summary Comparison of Energy Market Models

EPA performed research to identify electricity market models that could potentially be used in the analysis of impacts associated with the proposed section 316(b) Phase II regulation and other regulatory options. This research included reviewing available forecast studies and interviewing persons knowledgeable in the area of electricity market forecasting. EPA focused on identifying models that are widely used for public policy analyses, peer reviewed, of national scope, and have the capabilities needed to perform regulatory impact scenario analyses of the type required for the section 316(b) Phase II economic analyses. Based on this research, EPA identified three models that were potentially suitable for the analysis of the proposed section 316(b) Phase II regulations:

- (1) The Department of Energy's National Energy Modeling System (NEMS),
- (2) The Department of Energy's The Policy Office Electricity Modeling System (POEMS), and
- (3) ICF Consulting's Integrated Planning Model (IPM®).

Each of these models was developed to meet the specific needs of different end users and therefore differ in terms of structure, inputs, outputs, and capability. Table B3-A-1 below presents a detailed comparison of the three models. The comparison comprises:

- ***General features,*** including a description of each model, their general applications, and their environmental applications.

- ***Modeling features,*** including each model's treatment of existing environmental regulations, of industry restructuring, and of economic plant retirements; their regional capabilities; their plant/unit detail and data sources; their general data inputs and outputs; and their data inputs and outputs required for the section 316(b) analysis.

- ***Logistical considerations,*** including each model's costs, computational requirements, accessability and response time; their documentation and issues regarding disclosure of inputs or results; and general notes and references.

Table B3-A-1: Comparison of Electricity Market Models			
Model	**DOE/EIA: NEMS**	**DOE/OP: POEMS (OnLocation, Inc.)**	**EPA/Office of Air Policy (OAP): IPM (ICF Consulting Inc.)**
General Features			
Description	Modular structured model of national energy supply and demand, includes macroeconomic, international, supply and demand modules, as well as an electricity market module (EMM) that can be run independently. The EMM represents generation, transmission and prices of electricity. Based on forecasts of fuel prices, variable O&M, and electricity demand, determines plant dispatch to ***achieve the least cost supply of electric power***.	POEMS is a model integration system that allows the substitution of the TRADELEC model for the EMM in NEMS. TRADELEC allows for a greater level of detail about the electricity sector than the EMM. Designed to examine the effect of market structure transformation of the electricity sector. It solves for the trade of the commodity as a function of relative prices, transmission constraints and cost of market entry by ***maximizing economic gains*** achieved through commodity trading.	A production cost model based on linear programming approach, solves for least cost dispatch. Simulates system dispatch and operations, estimates marginal generation costs on an hourly basis. ***Minimizes present worth of total system cost*** subject to various constraints.
General Applications	Used to produce annual forecasts of energy supply, demand, and prices through 2020 for the Annual Energy Outlook. Can also be used to analyze effects of proposed regulations. EIA performs studies for Congress, DOE, other agencies.	Used by DOE's policy office to study the impacts of electricity market transformation/ deregulation through 2010. Supports the administration's 1999 bill on industry deregulation, the Comprehensive Electricity Competition Act (CECA).	Primary model used by EPA Air Program offices to evaluate policy and regulatory impacts through 2030. EPA Office of Policy also used this model for GCC and retail deregulation analysis. Used by over 50 private sector clients to develop compliance plans, price forecasts, market analysis, and asset valuation.
Environmental Applications	Includes a Carbon Emission submodule. Can also calculate emissions. Produced "Analysis of Carbon Mitigation Cases" for EPA.	DOE application generally not designed to perform environmental regulatory analysis. Examines a renewable portfolio standard. EPA/ARD concluded that air emission estimates are low relative to IPM and other models. However, DOE contractor has performed analyses of environmental policies for private clients.	Analyzes environmental regulations by simultaneously selecting optimal compliance strategies for all generating units. Can calculate emissions, and simulate trading scenarios. Used for ozone (NO_x), SO_2, and mercury emissions control scenarios; implementation of NAAQS for ozone and PM; alternative NO_x emissions trading and rate-based programs for OTAG, CAAA Title IV NO_x Rule; NO_x control options; RIA for the NO_x SIP call; and GCC scenarios. Possible to accommodate other environmental regulations.

Table B3-A-1: Comparison of Electricity Market Models			
Model	**DOE/EIA: NEMS**	**DOE/OP: POEMS (OnLocation, Inc.)**	**EPA/Office of Air Policy (OAP): IPM (ICF Consulting Inc.)**
Modeling Features			
Treatment of Environmental Regulations	Reference case represents all existing regulations and legislation in effect as of July 1, 1998, including impacts of the Climate Change Action Plan and the NO_x SIP call. EMM can analyze seasonal environmental controls to the extent that they match up with the seasonal representations in the model (non-sequential months are grouped according to similar load characteristics).	Assumes existing regulations and legislation remain in place and facilities comply with existing regulations in the least cost way. Most recent reference case analysis includes NO_x SIP call. Assesses a renewable portfolio in the competition case. Does not include other proposed or anticipated environmental regulatory scenarios in DOE analysis.	The base case includes current federal and state air quality requirements, including future implementation of SO_2 and NO_x requirements of Title IV of the CAA, the NO_x SIP call as implemented through a cap and trade program. Base case also includes assumptions regarding demand reductions associated with the Climate Change Action Plan.
Treatment of Restructuring	All regions assumed to have wholesale competition. Only states with enacted legislation are treated as competitive for retail markets in base case. Has a competitive pricing scenario that assumes full retail competition.	Designed to compare competitive wholesale and cost-of-service retail market structures to fully competitive market structure at the wholesale and retail levels. Compares prices and determines "stranded assets" at the firm level. Pricing modeled for 114 power control areas, assumes profit maximizing behavior.	EPA uses assumptions in IPM that reflect wholesale competition occurring throughout the electric power industry. Work for private clients uses different assumptions.
Treatment of Economic Plant Retirements	Uses assumptions about licencing and needs for new major capital expenses to forecast nuclear retirements. For fossil steam, model checks yearly to compare revenues at market price with future O&M and fuel costs to forecast economic retirements. Results appear to have second highest forecast of fossil steam retirements compared to other models.	Uses same method as NEMS for forecasting "forced" retirements of nuclear assets due to operating constraints such as licences. Economic retirements based on lack of ability to cover short term going forward costs and the cost of capacity replacement in the long term. Results appear to have highest forecast of fossil steam retirements compared to other models.	Uses assumptions about licencing in forecasting nuclear retirements. The IPM model retires capacity when unit level operating costs reach a level that total electric system costs are minimized by shutting down the existing unit.
Regional Capabilities	Model runs analysis for 15 supply regions.	Analyzes 114 power control areas connected by 680 transmission links.	Analyzes 26 supply regions that can be mapped to NERC regions.
Plant/Unit Detail	Groups all plants into 36 capacity types based on fuel type, burner technology, emission control technology, etc. within a region. Units or plants can be grouped differently according to §316(b) characteristics.	Units are grouped according to demand and supply regions, fuel type, prime mover, in-service period, similar heat rates. There are 6,000 unit groupings, an average of 55 per power control area. Plants can be re-grouped for §316(b).	Groups approximately 12,000 generating units into model plants. Grouped by region, state, technology, boiler configuration, location, fuel, heat rate, emission rate, pollution control, coal demand region. Plants can be re-grouped for §316(b).

Table B3-A-1: Comparison of Electricity Market Models

Model	DOE/EIA: NEMS	DOE/OP: POEMS (OnLocation, Inc.)	EPA/Office of Air Policy (OAP): IPM (ICF Consulting Inc.)
Modeling Features (cont.)			
Plant/Unit Data Sources	Form EIA-860A (all utility plants); Form EIA-867 (nonutility plants <1MW); Form EIA-767 (steam plants <10MW); Form EIA-759 (monthly operating data for utility plants).	Model includes "virtually all" currently existing generating units, including utility, exempt wholesale generators (EWGs), and cogenerators.	Over 12,000 generating units are represented in this model. Includes all utility units included in Form EIA-860 database. Plus IPPs and cogenerating units that sell firm power to the wholesale market. Also draws from other EIA Forms, Annual Energy Outlook (AEO), UDI, and other public and private databases. In addition, ICF has developed a database of industrial steam boilers with over 250 MMBtu/hr capacity in 22 eastern states.
General Data Inputs	Demand, financial data, tax assumptions, EIA and FERC data on capital costs, O&M costs, operating parameters, emission rates, existing facilities, new technologies, transmission constraints, and other inputs from other modules.	Inputs are similar to NEMS (for demand, fuel price and macroeconomic data), and EIA reports. FERC filings for other inputs such as capacity, operating costs, performance, transmission, imports, and financial parameters.	Some inputs are similar to NEMS, including demand forecast, and cost and performance of new and existing units. Emission constraints, repowering, and retrofit options are EPA specified. Fuel supply curves are used to model gas and coal prices.
Data Inputs for §316(b) EA	Would need to provide information on additional capital costs, O&M costs, study costs, outage period for technology installation, and changes in heat rate and plant energy use associated with ***each type of technology as it applies to each type of model plant***.	Would need to provide information on additional capital costs, O&M costs, outage period for installation, and changes in heat rate and plant energy use associated with ***each type of technology as it applies to each plant grouping***.	Would need to provide information on additional capital costs, O&M costs, outage period for installation, and changes in heat rate and plant energy use associated with ***each type of technology as it applies to each type of model plant***.
General Data Outputs	Retail price and price components, fuel demand, capital requirements, emissions, DSM options, capacity additions, and retirements by region and fuel type.	Dispatch, electricity trade, capacity expansion, retirements, emissions, and pricing (retail and wholesale) by region, state, and fuel type.	Regional and plant emissions; fuel, capital, and O&M costs; environmental retrofits; capacity builds; marginal energy costs; fuel supply, demand, and prices (primarily wholesale; one study focused on retail market).
Data Outputs for §316(b) EBA	Results would include additional economic retirements, changes in generation, and changes in revenues for ***each region and fuel type***. EMM cannot provide results on a state-by-state basis. By design, it is not possible to map model plant results back to specific plant/owner using current modeling approach.	Results would include additional economic retirements, changes in generation, and changes in revenues for ***each region and plant grouping***. Could map costs to units and owners with some modification of structure.	Results would include additional economic retirements, changes in generation, and changes in revenues for ***each region and model plant type***. Currently has ability to map back to specific unit and plant/owner. While this process is automated, it requires 2-3 days of manual checking for every year modeled.

Table B3-A-1: Comparison of Electricity Market Models			
Model	**DOE/EIA: NEMS**	**DOE/OP: POEMS (OnLocation, Inc.)**	**EPA/Office of Air Policy (OAP): IPM (ICF Consulting Inc.)**
Logistical Considerations			
Costs *(cost estimates should be considered very preliminary)*	No out-of-pocket costs expected.	Initial policy case using existing scenario: $15-20k. Setting up new base case scenario, performing several runs, and producing briefing: $40-60k. (Assumes plant re-grouping cost is included in second estimate only.)	Initial policy case: $20-30k. Incremental cases $2-10k. Re-grouping model plants would be labor intensive and add costs to analysis.
Computational Requirements	Setting up a policy case may take two months. The model run time is two hours without iterating with rest of NEMS, four hours for total NEMS iteration. EIA runs NEMS on RS6000 workstations.	Setting up and running policy case could take from a few days to a few weeks, depending on whether policy case builds on an existing scenario and the complexity of the policy scenarios.	Depends on number of model plants and number of years in analysis. Base case approximately 4-6 hours.
Accessability and Response Time	Access and response time dependent on agreement between EIA and EPA and EIA's schedule. Could be difficult to get results turned around in time to meet regulatory schedule, depending on EIA's reporting schedule.	Access and response time potentially dependent on agreement between DOE and EPA and DOE's schedule. Model run by a contractor. ARD has impression that model has long set-up time, model not set up to perform many iterations quickly.	ICF is an EPA contractor. Assume that access and response time will be consistent with requirements of analysis.
Documentation and Disclosure of Inputs/Results	Documentation and results already available to public. Presented by year for fuel type and region. Could make aggregated results publicly available. EIA does not release plant-specific results.	Documentation and results of reference and competition cases are available to public on DOE's web page.	Documentation of the EPA Base Case already available to public. Assume disclosure would be similar to that for NO_x SIP call, etc. EPA/ARD states that there is more in public domain regarding IPM than most models.
Notes	The NEMS code and data are available to anyone for their own use. Anyone wishing to use NEMS is responsible for any code conversions or setup on their own systems. For example, FORTRAN compilers differ between the workstation and PC. Several national laboratories and consulting firms have used NEMS or portions of it, but the time investment is considerable. One out-of-pocket expense is the purchase of an Optimization Modeling Library (OML) license. OML is used to solve the embedded linear programs in NEMS. In order to modify or execute one of the NEMS modules that includes a linear program (EMM is one of them), an OML license is required.	DOE's contractor stated that they may need to make some structural changes to the modeling framework to accommodate the requirements for §316(b) analysis so that the model can incorporate the effects of the additional costs into the decision process (either to continue running a plant or to retire and replace the plant).	OAP sensitive to other EPA offices using another model or using IPM with different assumptions. Willing to coordinate and provide background and technical support. The EPA Base Case has received some challenges over impacts of Climate Change Action Plan on end-use demand. However, has cleared OMB review under other regulatory proposals.

Table B3-A-1: Comparison of Electricity Market Models			
Model	**DOE/EIA: NEMS**	**DOE/OP: POEMS (OnLocation, Inc.)**	**EPA/Office of Air Policy (OAP): IPM (ICF Consulting Inc.)**
References	‣ Annual Energy Outlook 1999, Report#:DOE/EIA-0383(99); ‣ Assumptions to the AEO99, Report#:DOE/EIA-0554(99); ‣ EMM/NEMS Model Documentation Report, Report#: DOE/EIA-M0689(99); ‣ Personal communications with EIA staff: Jeffrey Jones (jeffrey.jones@eia.doe.gov) and Susan Holte (sholte@eia.doe.gov).	‣ POEMS Model Documentation, June 1998; ‣ Supporting Analysis for the Comprehensive Electricity Competition Act (CECA), May, 1999, Report#: DOE/PO-0059; ‣ The CECA: A Comparison of Model Results, September, 1999, Report#: SR/OAIF/99-04; ‣ Personal communications with DOE staff: John Conti (john.conti@hq.doe.gov), EPA staff: Sam Napolitano (napolitano.sam@epa.gov), and contractor: Lessly Goudarzi (goudarzi@onlocationinc.com).	‣ Analyzing Electric Power Generation Under the CAA (Appendix 2), March, 1998 (EPA/OAR/ARD); ‣ Analysis of Emission Reduction Options for the Electric Power Industry (Chapter 2), March, 1999 (EPA/OAR/ARD); ‣ IPM Demonstration, May, 1998 (slides by ICF); ‣ Personal communications with EPA staff: Sam Napolitano (napolitano.sam@epa.gov), and contractors: John Blaney (blaneyj@icfkaiser.com).

Source: U.S. EPA analysis, 2002.

B3-A.2 Differences Between the EPA Base Case 2000 and Previous Model Specifications

Past applications by EPA of the IPM model have employed a predecessor base case specification. The previous specification of the IPM model, EPA Base Case 1998, was recently updated to the current EPA Base Case 2000. The revised specification used for the section 316(b) analysis uses more complete and current cost and performance data for new and existing facilities, updated demand growth forecasts, and revised financial, fuel cost, and regulatory assumptions. The primary differences between the IPM's EPA Base Case 2000 and its predecessor model specification are identified and discussed below. For more a more detailed discussion of the specification of the EPA Base Case 2000 see *Documentation of EPA Modeling Applications (V.2.1) Using the Integrated Planning Model* (U.S. EPA, 2002).

- The National Electric Energy Data System (NEEDS), the database containing location, operational, and emission data for each of the existing and planned-committed generating units modeled in each IPM base case specification, was updated using 1998 EIA data taken primarily from Form EIA-860A, Form EIA-860B, Form EIA-759, and Form EIA-767. In addition, the update used data from the 1998 NERC Electric Supply and Demand database, second quarter values from EPA's 2000 Continuous Emission Monitoring System database, and the EPA 1999 Information Collection Request database.

- The EPA Base Case 1998 demand growth assumptions were updated for the EPA Base Case 2000 specification. The demand growth assumptions for the original specification were based on the 1997 NERC Electricity Supply and Demand forecast for Net Energy for Load in early years, and on the Data Research Institute (DRI) 1995 forecast for later years. These original forecasts were adjusted based on EPA's estimate of the demand reductions resulting from implementation of the Climate Change Action Plan (CCAP). The EPA Base Case 1998 electricity demand growth rate was 1.6 percent per year for 1997-2000, 1.8 percent per year for 2001-2010, and 1.3 percent per year for beyond 2010. EPA Base Case 2000 electricity demand growth is based on the AEO 2001 forecast. The AEO 2001 forecast was also adjusted to account for impacts of initiatives created under the CCAP in the revised base case specification. The EPA Base Case 2000 average annual growth rate in Net Energy for Load is 1.2 percent for 2000-2020.

- Fuel Price assumptions were also updated under the EPA Base Case 2000 specification. Revised fuel price forecasts/ supply curves for nuclear and biomass assumptions were taken from AEO2000 and AEO2001, respectively, and natural gas information was derived from ICF's Gas Systems Analysis Model (GSAM).

- The underlying assumptions affecting the retirement of fossil fired and nuclear capacity under the original specification were revised for EPA Base Case 2000. Fossil power plants are given no fixed retirement date in EPA Base Case 2000 as compared to EPA Base Case 1998 where they were assumed to have a finite lifetime. In the EPA

Base Case 2000 retirement is determined endogenously based on economics. In addition, the option of re-licensing nuclear units was introduced for EPA Base Case 2000, based on AEO2000 nuclear capacity factor forecast data. Nuclear units that had not made a major maintenance investment, at age 30, are provided with a 10-year life extension. These same units may subsequently undertake a 20-year re-licensing option at age 40. Nuclear units that already had made a maintenance investment are provided with a 20-year re-licensing option at age 40. All nuclear units are ultimately retired at age 60.

- The cost and performance characteristics of new and existing units as well as environmental control technologies such as SO_2 scrubbers, selective catalytic reduction, and activated carbon injection were updated using more recent data for the EPA Base Case 2000 specification. For example, the O&M costs for existing units were updated to include the cost of capital additions. Further, the cost and performance assumptions for new units were updated using information presented in AEO2000.

- The financial assumptions for environmental control options and new units were revised based on recent market activity. The capital charge rate and discount rate in EPA Base Case 1998 were 10.4% and 6%, respectively. For the EPA Base Case 2000 specification the capital charge rate and discount rate were revised to 12% and 5.34%, respectively, for retrofits; 12.9% and 6.14%, respectively, for new combined cycle units; and 13.4% and 6.74%, respectively, for new combustion turbine units.

- The EPA Base Case 2000 uses updated transmission assumptions. EPA Base Case 2000 organizes the United States into 26 different power market regions for analyzing inter-regional electricity transfers across the interconnected bulk power transmission grid as compared to 21 power market regions in EPA Base Case 1998. Assumptions regarding transmission capabilities in the EPA Base Case 2000 were updated based on more recent NERC documents.

- The EPA Base Case 2000 is updated to account for additional environmental regulations. Specifically, EPA Base Case 2000 accounts for EPA's NO_x SIP Call regulation, a trading program covering all fossil units in 19 northeastern states during the ozone season (May-September). In addition, state level environmental regulations in Texas, Missouri, and Connecticut are also modeled.

- The aggregation scheme for model plants was revised under EPA Base Case 2000. The group of coal fired model plants was further disaggregated based on power plant firing type, fine particulate controls, and post combustion NO_x controls.